Decision 04-12-045 December 16, 2004

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Incentives for Distributed Generation and Distributed Energy Resources.	Rulemaking 04-03-017 (Filed March 16, 2004)

ORDER TO MODIFY THE SELF GENERATION INCENTIVE PROGRAM AND IMPLEMENT ASSEMBLY BILL 1685

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1. Summary

This decision adopts modifications to the Self Generation Incentive Program (SGIP), which provides incentives to businesses and individuals who invest in distributed generation. We implement the provisions of Assembly Bill (AB) 1685, eliminate the maximum percentage payment limits, and reduce the incentive payments for several technologies, including Level 1 solar projects, which we reduce to $3.50 per watt, effectively immediately. We also eliminate the “maximum percentage payment limits,” which have caused considerable administrative complexity. We direct the SGIP program administrators to expand opportunities for public input in three Working Group activities: developing a declining rebate schedule, developing an exit strategy, and adapting a data release format.

Program costs will continue to be included in utility distribution revenue requirements. The utilities will track these costs in the SGIP memorandum accounts created by Decision (D.) 01-03-073 for recovery in their respective general rate cases or other authorized proceedings.

2. Background

The Commission adopted certain load control and distributed generation initiatives on March 29, 2001, pursuant to AB 970. We authorized a total budget of $137.8 million annually through 2004: $12.8 million for load control, and $125 million for self generation. Under the self generation program adopted in D.01-03-073 and modified in D.02-09-051, certain entities qualify for financial incentives to install three different categories (or levels) of clean and renewable distributed generation used to serve some portion of a customer’s onsite load:

Level 1: The lesser of 50% of project costs or $4.50/watt for photovoltaics, wind turbines, and fuel cells operating on renewable fuels;

Level 2: The lesser of 40% of project costs or $2.50/watt for fuel cells operating on non-renewable fuel and utilizing sufficient waste heat recovery,

Level 3:

- 3-R: The lesser of 40% of projects costs or $1.50/watt for microturbines, internal combustion engines, and small gas turbines utilizing renewable fuel.
- 3-N: The lesser of 30% of project costs or $1.00/watt for the above combustion technologies operating on non-renewable fuel, utilizing sufficient waste heat recovery and meeting certain reliability criteria.

The Commission recognized that certain events, such as legislation, market activity, or outcomes of the SGIP program evaluation process, could require modifications to the SGIP during the course of the program. In subsequent orders, the Commission took actions to refine the program, such as adopting a reliability requirement, developing renewable fuel criteria, and increasing the maximum eligible size from 1 MW to 1.5 MW.

On October 12, 2003, the Governor signed AB 1685. The legislation adopts emissions and efficiency requirements that fossil-fueled DG projects must meet in order to be eligible for SGIP rebates, and extends the SGIP through December 31, 2007. The new emissions standards go into effect in two phases: January 1, 2005, and January 1, 2007.

On September 27, 2004, the Governor signed AB 1684. This law makes projects that operate on waste gas eligible for incentives, subject to certain requirements in the law.

On December 10, 2003, an Administrative Law Judge (ALJ) ruling issued in Rulemaking (R.) 98-07-037 requested comments to the evaluation reports prepared by Itron, as well as on other SGIP-related issues.

On July 9, 2004, the ALJ issued a ruling seeking comments on an Energy Division report that recommended program modifications.

The following organizations responded to one or both ALJ rulings: Pacific Gas & Electric Company (PG&E), Southern California Edison Company (SCE), Southern California Gas Company and San Diego Gas & Electric (Sempra), California Solar Energy Industry Association (CALSEIA), The Center for Energy Efficiency and Renewable Technologies (CCERT), Distributed Energy Strategies (DES), Joint Parties Interested in Distributed Generation[1] (JPIDG), Powerlight Inc. (Powerlight), RWE Scott Solar Inc., MegaWatt Inc., Sacramento Municipal Utility District (SMUD), The City and County of San Francisco (San Francisco), the City of Oakland/Rahus Institute, Prevalent Power, Uni-Solar, Occidental Power, Borrego Solar Systems Inc.,[2] and the California Fairs Alliance of Western Fairs Association (Western /Fairs). This decision resolves the issues addressed in Energy Division's report.

3. Discussion

3.1 Incentive Levels and Size Limits

Under the current structure, incentives are based on a project's generating capacity, measured in watts. The incentive payment is capped at a certain

[1] JPIDG membership includes Capstone Turbine Corporationems Inc., Chevron Energy Solutions, Cummins Cal-Pacific, Cummins, Inc., next.edge, Inc., Northern Power Systems, Inc., Real Energy Inc., Simax Energy, and Solar Turbines, Inc.

[2] Borrego represents Eco Energies, Inc., Sun Light and Power, Quality Solar, and CC Energy.

percentage of eligible installed costs. Both the per-watt payment and the percentage cap vary by technology level. For example, a solar panel project receives $4.50 per watt of capacity, up to a maximum of 50% of eligible installed project costs.

The Working Group and program applicants have described the time-consuming process to prepare and review hundreds of pages of itemized project costs to determine whether the costs are eligible under the incentive cap. Energy Division proposes to remove the maximum percentage cap, and to set incentives according to installed capacity. Energy Division believes this approach would be simpler and less costly for program administrators and applicants, would accelerate the rebate payment process, and provide an incentive for developers to reduce project costs. As an alternative, CALSEIA and Capstone propose to allow applicants to select one of two approaches, either a dollar per watt or percentage cap structure, on a project-by-project basis. We find that it is reasonable to adopt the Energy Division's recommendation and will set incentives according to installed capacity. Streamlining the SGIP program is in the public interest. In addition, we reduce the per-watt incentive, as discussed below.

The Energy Division report also recommends the Commission adopt CALSEIA's proposal to reduce Level 1 incentives from $4.50 per watt to $4.05 per watt. Program administrators have exceeded their allocated Level 1 budgets for 2004, and have transferred funds from other categories in an effort to meet

Level 1 demand. Both PG&E and SDREO created waiting lists to ensure an orderly reservation process once additional funding becomes available.

While parties agree that the Commission must reduce incentive payments, most believe CALSEIA's proposed incentive payment is too high. To support this claim, PG&E provides an analysis which indicates some projects would actually receive higher incentive payments under the combined effect of eliminating maximum percentage limits and instituting rebates of $4.05 per watt. The Working Group supports reducing Level 1 incentives for solar projects to $3.00 per watt and eliminating the maximum percentage cap, which is the CEC's current model for similar projects.

The Working Group also recommends reducing per-watt incentives for wind turbines and Level 3-R projects to reflect the decrease of installed costs for these technologies, maintaining Level 3-R incentive levels for internal combustion engines, and increasing incentives for microturbines utilizing renewable fuel.

We agree that the incentives must be reduced in order to meet the demand for incentives in 2004 and in light of the limited funding available to solar projects over 30 kW. Reducing the incentives would help meet the short-term need to assure the broadest dispersion of funds. Moreover, some of the incentives are too high relative to known technology costs.

Since most program administrators have exhausted their 2004 funds, we believe changes in incentive levels must occur simultaneously and immediately. As of the effective date of this decision, the new incentive structure for Level 1 wind and solar projects will apply to those projects that have not received a conditional reservation letter, including those projects on waiting lists. Level 1 projects will receive incentive payments of $3.50 per watt. We will order that this level be reduced to $3.00 effective January 1, 2006. Incentive payments for renewable fuel cells will remain at $4.50 per watt. We change several other incentive levels while concurrently eliminating the maximum percentage payment limits. We adopt those recommendations of the Working Group for changed incentive levels, which they developed considering the Itron report and program experience. The combination of reducing some incentives with removing the maximum percentage payment limits will reduce administrative complexity and free up funds for additional projects while better recognizing the costs of each technology.

We make no changes to per-watt incentives for Level 1 and Level 2 fuel cells, as these projects have not yet achieved market penetration levels that would likely lead to lower production and project installation costs. We clarify that maximum percentage caps are lifted for all levels, including fuel cells.

We agree with PG&E that at some point, the Level 1, Level 2, and Level 3 categories may no longer be the most practical method to group disparate technologies. However, because we do not modify the budget allocations assigned to various technologies, we retain the current categories for purposes of tracking budget allocations, reallocations, and incentive availability.

Effective immediately, the new incentive payments for each category are as follows:

	Technology	Incentive (per watt)
Renewable	Level 1 • Fuel Cells • Photovoltaics Level 3-R • Microturbines • Wind Turbines • Internal Combustion Engines	 $4.50 $3.50, decreasing to $3.00 on 1/1/2006 $1.30 $1.00 $1.00 $1.00
Non-renewable	Level 2 • Fuel Cells Level 3 • Microturbines and Gas Turbines • Internal Combustion Engines	 $2.50 $0.80 $.060

PG&E requests that the Commission determine how to treat applications on waiting lists at the end of December 2004. Under current SGIP rules, program administrators must carry over any unused funds to the next program year. The rules also require projects that remain on a waiting list at the end of the year to reapply the following year. As of July 23, 2004, PG&E's waiting list had 109 solar projects requesting $76.6 million, despite repeated reallocations to Level 1. PG&E closed the waiting list on August 1, 2004. It is unlikely PG&E or SDREO will have funds to carry over to 2005. Under the current budget and program structure, if PG&E were to fund the wait-listed projects immediately with 2005 funds, PG&E could once again be oversubscribed in early 2005.

We agree with PG&E that these vendors should not have to submit new applications on January 1, 2005. A combination of the programmatic changes we adopt today: the reduced incentives and elimination of the maximum cap will optimize funding availability for viable projects. We direct the Working Group to develop a process whereby applicants whose projects are on waiting lists at the end of the year will not need to reapply in 2005.

Decision 01-03-073 adopted a maximum project capacity size to 1 MW for all eligible technologies, and set a minimum size of 30 KW for Level 1 projects. A subsequent decision increased the project size cap to 1.5 MW, but retained the 1 MW payment cap. Several parties suggest the Commission could increase the maximum capacity requirement again without raising the incentive payment beyond 1 MW. Proposals range from 2MW to 20 MW. DES asserts that allowing larger projects to participate will add substantial new capacity without claiming excessive funds or reducing the number of projects that can participate. PG&E raises concerns over the potential for "free ridership," for example, financially viable large projects that would be constructed without incentives. We adopt Energy Division's proposal to increase maximum eligible capacity size to 5 megawatts, effective January 1, 2005. Increasing capacity size will allow developers, customers, utilities, and ratepayers to receive cost savings achieved by larger projects. However, we will continue to limit incentive payments to 1 MW of capacity. We share PG&E's concern that increasing incentive payments from 1 MW to 5MW would allow only a few projects, particularly Level 3 technologies, to receive incentives before depleting a program administrator's entire annual budget.

The incentive levels we adopt today are based on the best available information we have at this time. We may revisit these levels following our adoption of a cost-benefit methodology in Phase 2 of this proceeding. A cost-benefit methodology for distributed generation projects will permit us to determine an appropriate level of incentives, whether higher or lower, and on the basis of a comparison of DG projects with other energy resources.

3.2 Administrative Budget

The administrative budget adopted in D.01-03-073 authorizes each Program Administrator to allocate up to 20% of the SGIP budget toward administrative costs. These costs include, but are not limited to measurement, verification, and evaluation activities, marketing, outreach, and regulatory reporting.

As discussed in Section 3.1, we anticipate that removing the maximum percentage caps will reduce administrative costs. The Working Group proposes to reduce the total administrative budget to 10%, which would allow 90% of the SGIP budget to be paid out in rebates. We concur with this approach and herein adopt it.

3.3 Incentives from other Sources

The Working Group makes the observation that current rules permit projects to receive funding from multiple sources. Such incentives are available from several agencies and organizations. Because we herein eliminate the maximum percent of eligible project costs, we need to address how the incentives adopted herein will be calculated where a project receives other funding. We agree with the Working Group's recommendations to calculate the SGIP as a "last rebate" applied after taking into account any other rebates and that total rebates cannot exceed the payments made by the system owner to purchase the system. We also agree that where a project accepts payments based on future performance, the project should not be granted SGIP payments. These restrictions are intended to protect ratepayers from paying projects more than they cost, and to assure that funding is available to promote as many projects as possible. We ask the Working Group to monitor SGIP payments to projects that receive other incentives, and to recommend changes, if any, to the rules that protect ratepayers and funding sources while continuing to promote development of good projects.

3.4 Treatment of Program and Project Data

The scoping memo in this proceeding discusses a number of issues related to DG data collection and dissemination, including but not limited to data collected under the SGIP. Today's decision does not address options to streamline collection and availability of data related to interconnection, net metering, and cost responsibility surcharge exemptions. These issues will be addressed later in the proceeding.

In the meantime, we adopt Energy Division's recommendation to create a data release format that resembles the format used by the California Energy Commission (CEC) Emerging Renewables Incentive Program. Although the categories of data of the two programs may differ to some extent, we direct the Working Group to develop a common format that provides similar project information, including but not limited to:

- Seller, installer, developer, or applicant, as appropriate;
- City and zip code;
- Utility name;
- Technology (including model and manufacturer);
- Capacity size;
- Installed price; and
- Inverter model and manufacturer, where applicable.

The Working Group has already made substantial progress toward releasing this information, as demonstrated by a review of the program administrator websites.

We direct the Working Group to develop and circulate proposed formats for discussion among Working Group members and interested parties. The Working Group may also designate one or more program administrator to confer with interested parties in order to obtain broader input for developing the format. Each program administrator should post the required information to its website within 30 days of the effective date of the decision.

We also direct program administrators to post certain program information to their websites, including the amount of funds reserved, paid, and available in each level, funds transferred between levels, and installed and reserved generating capacity. The format should be consistent among administrators.

3.5 Declining Rebates and Exit Strategy

A report written for the Commission by Itron titled "Second Year Impacts Report," raises concerns regarding the impacts an abrupt termination of the SGIP program would have on markets for renewable and clean DG. Itron recommends the Commission adopt an exit strategy based on a declining incentive structure to ensure a smooth transition to a market no longer supported by SGIP rebates. The Energy Division and parties unanimously support the recommendation.

We agree that a declining incentive structure will gradually reduce the market's reliance on a subsidy. This incentive structure should be predictable and transparent, with a specific schedule, rather than applying program milestones such as dollars expended or capacity installed. We herein direct the Working Group to propose a plan to phase out the incentives in a predictable way. However, we are not prepared to state intent to terminate the program at the end of 2007. The requirements set forth in AB 1685 for the Commission to implement the SGIP end at that time. The Commission, however, is thereafter within its authority to continue funding for and implementation of the program. The state has expressed a strong commitment to distributed generation and renewable energy technologies, for example, in the Energy Action Plan, and three additional years of program funding may not be adequate to assure optimal development of those energy resources. The Working Group's recommended incentive phase-out should therefore anticipate a continuation of the program through the end of 2014.

The Working Group shall file a proposed exit plan, which includes specific calendar dates and a table of incentive levels, within 90 days of the effective date of this order. The declining schedule may vary by technology, if appropriate. The Working Group shall organize at least one open meeting with industry participants and interested parties to obtain broader input on these issues, prior to submitting its proposed plan.

After Commission review and approval of a phase-out plan, the program administrators should post the plan elements on their websites and include the schedule in the program handbook.

3.6 Program Evaluation and Cost Effectiveness

The Commission is considering several DG-related evaluation activities in this and other proceedings. While parties unanimously support a cost-effectiveness study of the SGIP, others seek clarification regarding the purpose of seemingly duplicative cost benefit work, and whether these activities could be consolidated. We describe the evaluation, cost benefit, and cost effectiveness issues under review.

In D.01-03-073, we directed the program administrators to evaluate program success and conduct load impact studies to verify energy production and system peak demand reduction. As observed by Itron and others, many projects that applied for incentives in 2001 were not completed until 2003 or later. Accordingly, Itron had very little production data available for analysis. With over 72 MW installed to date, the program is now better situated for the monitoring, data collection, and evaluation activities envisioned by D.01-03-073. Itron filed the Program Year 2003 evaluation report in October 2004. We intend to address subsequent evaluation plans in a future decision.

Decision 01-03-073 also directed the Energy Division to retain a consultant to study and develop recommendations concerning cost-effectiveness assumptions used to evaluate energy efficiency, demand response, or distributed generation projects and programs. A subsequent decision, D.03-04-055, refined the scope of work to update the avoided costs and externality adders presently used to evaluate energy efficiency programs. These avoided costs and externality adders constitute some, but not all, of the required inputs to the Standard Practice Manual (SPM) cost effectiveness tests. The firm, Energy and Environmental Economics, Inc. (E3) prepared and submitted a report to the Commission in January 2004. The E3 report was finalized on October 25, 2004, and its potential application will be closely examined in R.04-04-025, which is reviewing avoided costs. In that rulemaking, the Commission intends to develop a common avoided cost methodology, consistent input assumptions, and updating procedures for avoided costs which would apply in all resource-related decision-making, such as those applying to qualifying facilities, energy efficiency, and DG.

In R.04-03-017, we intend to develop an overall DG cost-benefit methodology. We indicated we would, to the extent possible, consider other cost effectiveness tests, such as those described in the E3 report, the SPM, and input assumptions from the E3 report. As part of the SGIP evaluation process, Itron is preparing a report that will address the applicability of these and other methodologies for the purpose of assessing the cost-effectiveness of the SGIP. Itron's proposed cost-effectiveness framework is expected to be issued for comment before the end of the year. Based on the proposed framework and parties' comments, Itron will prepare and submit the SGIP cost-effectiveness study for comment. The August 6, 2004 Assigned Commissioner's Scoping Memo issued in this proceeding directed parties to propose cost-benefit methodologies in testimony due October 4, 2004, scheduled hearings for November 2004 and anticipates a proposed decision on a DG cost-benefit methodology by February 2005. Because of the timing of the Itron report and its obvious tie-in with the issues scheduled to be addressed in hearings, the ALJ recently rescheduled hearings on cost-benefit issues so the parties and the Commission may consider the findings and conclusions of the Itron report in hearings and a subsequent Commission order. We also intend to closely coordinate the modeling efforts in this proceeding with those in the proceeding in which we review energy avoided costs, R.04-04-025.

Ideally, we would adopt a cost benefit methodology prior to an analysis of SGIP cost-effectiveness. However, these two related efforts can be conducted concurrently, and updated as necessary. Itron intends to submit an interim SGIP cost-effectiveness report by February 15, 2005, and update the report in

December 2006, if necessary, to reflect the methodology ultimately adopted by the Commission. We intend to proceed to adopt a final cost-benefit methodology following hearings.

3.7 Program Administration Through 2007

Consistent with D.01-03-073, Itron also prepared and submitted a report that compares utility and non-utility program administration. The report did not recommend one approach or the other, concluding that both types of administrators brought strengths and weaknesses to the program.

SDREO's contract with SDG&E expires on December 31, 2004, which coincides with the end of SGIP adopted in D.01-03-073. Since AB 1685 requires the SGIP to continue through 2007, SDREO seeks to continue SGIP administration in San Diego. SDG&E prefers to perform the administrative function within the utility, and to allow SDREO's contract to expire.

Energy Division recommends that the Commission continue to retain SDREO to administer the SGIP in SDG&E's service territory through 2007, approve SDREO's request for interval disbursement of program funds from SDG&E, and direct SDG&E to eliminate duplicative administrative functions. Staff recommends SDG&E update its contractual arrangements with SDREO to reflect these provisions.

SDREO asks the Commission to clarify the purpose of third-party administration, asserting that SDG&E duplicates the review and approval functions performed by SDREO on SGIP projects. SDREO contends that these duplicative efforts delay issuance of incentive payments. SDREO believes that under the current contract arrangement, SDREO is not a truly independent, non-utility administrator.

SDG&E replies that the utility, not SDREO, is the entity ultimately held accountable by the Commission. SDG&E points out that Itron's evaluation of utility and non-utility administration concludes that SDREO's administrative costs per kW achieved through the program were almost double of one or more utility administrators. SDG&E seeks utility administration, but at a minimum, requests recovery of utility costs for incremental activities such as interconnection safety, contract management, and responsibility for program administrator expenses.

The interval between issuance of the conditional reservation and the incentive payment is typically 12 months or more. This is due primarily to the amount of time required for project design, construction and installation. SDG&E disburses funds to SDREO based on the amount of incentive payments each month, and posts the amount in a memorandum account. SDG&E argues that ratepayers would shoulder significantly higher costs if the SGIP budget is disbursed to SDREO annually.

PG&E points out that SDREO has provided valuable contributions over the first three program years, and that only three years of the program remain. PG&E recommends that the Commission address larger questions concerning third-party administration of utility programs in other dockets and programs.

SDG&E does not provide an estimate of the incremental costs associated with annual disbursement. The Itron administrator comparison report, as well as the impacts and process reports, do not identify which utility administrator is associated with specific program measures. It is difficult, if not impossible, to assess the strengths and weaknesses of each program administrator. Subsequent reports should clearly identify all program administrators, and address the performance of each.

By D.01-03-073, we decided to explore non-utility administration of the SGIP "on a limited basis."[3] We did so in response to comments on Energy Division's report and, in particular, concerns raised by TURN and others about the utilities' motivation to aggressively pursue self-generation projects at that time.[4] Accordingly, we directed SDG&E to contract with SDREO to provide administrative services for the self-generation programs in SDG&E's service territory. However, we also acknowledged that D.01-03-073 was not the appropriate forum for addressing the administrative structure of energy efficiency and self-generation programs for the longer-term, and reserved judgment on these issues.

We are currently in the process of carefully evaluating the policy and legal issues associated with program administration alternatives in our energy efficiency rulemaking, R.01-08-028. Although we have not made our final determinations in that proceeding, we do note that the contractual arrangements we adopted for administrative services in D.01-03-073 places SDG&E in the role

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[3] D.01-03-073, mimeo. p. 17.

[4] *Ibid.*, pp. 17-18. In its report, Energy Division considered utility administration to be the expedient approach through at least 2001, and SDG&E, SCE and SoCal recommended that utility administration be established through 2004. PG&E suggested that the Commission consider alternatives to utility administration if the expectation was to have utilities gear up for only a one-year assignment. ORA, on the other hand, recommended that SDG&E contract with SDREO to provide administrative services for the program in SDG&E's service territory and, for the longer-term, that the Commission establish a network of Commission-certified regional energy offices to become administrators of both energy efficiency and self-generation programs. TURN recommended that alternatives to utility administration be pursued because, in its view, the utilities presented positions in the distributed generation rulemaking (R.99-10-025) that reflected their perception that self-generation would reduce distribution revenues.

of overseeing a contract with a third-party deliverer (SDREO) of administrative services for the SGIP program. In that role, we expect SDG&E to exercise prudent oversight to ensure that SDREO performs administrative services effectively and consistent with program guidelines. At the same time, SDG&E's oversight should not entail unreasonable duplication of effort (*e.g.*, re-reviewing in detail every single SGIP application that SDREO has processed) or unreasonably delay payments of incentives to qualified projects or to SDREO for administrative services rendered. We are extremely concerned about the timeliness of rebates to projects, as well as the additional cost associated with a duplicative review process. Thus, we believe that SDG&E and SDREO should be able to negotiate modified contract terms that allow for periodic progress payments or other similar provision, subject to random auditing or cross-checking by SDG&E. Energy Division should continue to mediate between SDREO and SDG&E on these issues.

Until we have fully addressed the legal and policy issues related to program administration in R.01-08-028, we believe that directing SDG&E to extend its administrative services contract with SDREO through 2007 is the best course of action. This approach enables the SGIP program to move forward without disruption to current program administration arrangements for the authorized funding period. At the same time, it does not preclude us from reevaluating the administrative structure for SGIP if funding continues past 2007. We authorize the program administrators to direct their consultant to update the September 2, 2003 comparative assessment report with data collected from June 2003 through May 2006 for submission by September 15, 2006. As directed above, the report should clearly identify all program administrators, and address the performance of each. We will then be in a better position to consider how best to administer the SGIP program beyond 2007, based on this report, our final determinations regarding program administration in R.01-08-028, and other relevant information.

We reject SDG&E's argument that the utility should receive additional funds to provide SDREO with interconnection and other utility expertise. Utility program administrators receive internal technical support; SDREO must receive similar treatment.

3.8 Emission and Efficiency Requirements

Currently, the Commission requires a Level 3 applicant to submit a permit to operate or other documentation issued by their local air district, approving the unit for operation. Air permitting requirements vary by location.

The Commission also requires Level 3 projects operating on nonrenewable fuel to meet a cogeneration efficiency of 42.5%, as specified in Pub. Util. Code § 218.5. A unit's anticipated efficiency is calculated as the sum of electricity produced and 50% of utilized output, divided by fuel input, based on the unit's average annual consumption.

Assembly Bill 1685 requires combustion-operated fossil-fueled DG projects to meet statewide emissions criteria to qualify for SGIP incentives. Projects must not emit over 0.14 pounds of nitrogen oxides (NOx) per MWh (ppMWh) as of January 1, 2005. By January 1, 2007, units must reduce emissions to 0.07 ppMWh, and achieve a minimum efficiency of 60%. Efficiency is to be calculated as useful energy output divided by fuel input, based on 100% load.

Units that do not meet the 2007 emissions standard may receive “extra credit” for meeting the 60% efficiency standard. [5]

To date, the California Air Resources Board (CARB) has certified just two technologies, microturbines and fuel cells, as able to meet the 2007 air emissions limit.

Energy Division’s report recommends program administrators verify a DG unit’s compliance with AB 1685 in one of two ways. The unit is automatically eligible for the SGIP if it is certified by CARB. If the unit is not certified by CARB, an applicant may demonstrate eligibility through the existing process, by submitting manufacturer emission specifications, a permit to operate, and project-specific efficiency calculations.

The staff proposal is the most practical approach for applicants to demonstrate compliance with AB 1685 compliance until CARB certifies additional technologies. As suggested by some parties, we clarify several related issues here. First, we agree with the Working Group that the term “commencing” as the term is used in Section 379.6 of AB 1685 should refer to the date on which a program administrator receives an SGIP reservation request form from a project proponent. Therefore, all projects which submit such forms on or after January 1, 2005 shall meet the new emissions standards.

Second, we interpret Section 379.6 (3), enacted by AB 1685, to require that the “credit to meet the applicable oxides of nitrogen” refers to both Section 379.6(1) and (2).

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[5] The credits specified in AB 1685 should not be confused with emissions trading credits, which is a different process not regulated by the CPUC.

Third, we find that in enacting Section 379.6, AB 1685 did not intend projects to be exempt from the preexisting thermal efficiency requirements of Section 218.5. Moreover, we believe those thermal efficiency requirements are reasonable and serve the public interest. Therefore, in order for projects to qualify for SGIP funding, the requirements of both Section 379.6 and Section 218.5 must be fulfilled.

The Working Group presented a model for how the eligibility process should work for fossil fuel projects, which we agree is a reasonable interpretation of the statute. Specifically, for the period 2005-06, a project is eligible if it either (1) meets the .14 NOx standard or (2) meets the 60% thermal efficiency standard and meets the .14 NOx standard with a NOx credit. In 2007 and thereafter, projects would need to either (1) meet the .07 NOx standard and the 60% thermal efficiency level or (2) meet the 60% thermal efficiency requirement and meet the .07 NOx standard with a NOx credit.

We direct the Working Group to modify the program handbook to reflect the AB 1685 emissions and eligibility requirements, as described herein, and the options we adopt for demonstrating compliance.

3.9 Participation in the SGIP Working Group

The purpose of the Working Group is to ensure program implementation in accordance with Commission policies. It is comprised of SCE, SDG&E, SoCalGas, PG&E, the Commission's Energy Division, CEC, and SDREO. In D.03-08-013, we adopted a process whereby market participants may meet with the Working Group to propose specific program modifications for the Commission's consideration.

The Energy Division's report recommended a process for expanding membership in the Working Group's activities, should the Commission determine that such expansion was appropriate. However, based on parties' comments and our prior determinations regarding Working Group structure, we still find that the Working Group membership is appropriate to its purpose. Nonetheless, we believe the Working Group's development of a proposed exit strategy, declining rebate schedule and common data release format would benefit from broader public input. As discussed above, we direct the Working Group to consult with interested parties in developing recommendations on these issues for our consideration. We also direct the Working Group to consult with interested parties as it incorporates changes to the program handbook to reflect today's determinations.

3.9.1 Program Eligibility

Decision 01-03-073 prohibited utility distribution companies from receiving SGIP incentives. The Working Group seeks clarification as to which distribution companies are excluded from the program.

We clarify that public and investor-owned gas or electricity distribution utilities which generate or purchase electricity or natural gas for wholesale or retail sales, are not eligible to receive incentives.

4. Other Issues

4.1 Corporate Parent Limits

Powerlight contends that projects located on county fairgrounds should be subject to the annual 1 MW corporate/government parent cap per utility service territory. Powerlight states that the fairgrounds are not independent entities, but are overseen by California's State and County Fairgrounds, the Division of Fairs and Expositions, and the California Construction Authority.

Western Fairs and Vote Solar argue that each county fair is a unique, separate, and self-funded entity similar to a school district. Each has its own board of directors, and different legal structures. Most are District Agricultural Associations. Some are non-profits, and others are county organizations. None are state agencies. Moreover, Vote Solar states that average project costs for these solar installations are $4.64 per watt, which is considerably lower than the average SGIP rebate.

DES and JPIDG seek to expand MW eligibility under the parent cap. Capstone questions why the Commission restricts the entities most likely to install DG: a statewide network of grocery stores and other retail chains. We agree that putting caps on funding for government and corporate parents hinder the goal of increasing DG capacity to reduce peak demand, and may inflate project costs to artificially high levels. We do not rule today whether or not county fairgrounds are subject to a cap. Rather, we remove the 1 MW per service territory parent cap that limits funding for the university system, other state and federal agencies, corporations, and other entities formerly subject to the cap. We clarify that the SGIP will not pay incentives for capacity over 1 MW per location through the life of the program.

4.2 Reservation Requests

CALSEIA suspects that certain project developers submit incentive reservation requests for "phantom" projects, in order to reserve funds for undeveloped future projects. CALSEIA states that these practices allow developers to tie up substantial funding that could be reserved for legitimate projects.

Under current program rules, an applicant must provide proof-of-project documentation within 90 days of receiving a conditional reservation request. A program administrator may grant an extension based on project circumstances.

CALSEIA recommends the Commission adopt additional mechanisms to deter phantom projects, such as requiring a nominal fee when an application is submitted, refundable upon project completion. We are not opposed to such a mechanism, provided it does not place an undue financial burden on smaller projects. We delegate to the Working Group the task of developing appropriate procedural or financial mechanisms to deter inappropriate reservation requests.

5. Comment on Draft Decision

The draft decision of the Administrative Law Judge in this matter was mailed to the parties in accordance with Pub. Util. Code § 311(g)(1) and Rule 77.7 of the Rules of Practice and Procedure. Comments were filed on November 8, 2004, and reply comments were filed on November 15, 2004. This decision includes several corrections and changes from the draft decision to reflect reasonable concerns of the parties with regard to the Working Group, the interim use of Itron modeling and administration by SDREO. It also modifies some of the incentive levels and clarifies the requirements for meeting AB 1685 air quality standards.

6. Assignment of Proceeding

Michael Peevey is the Assigned Commissioner and Kim Malcolm is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. The demand for incentives in 2004, combined with limited funding for projects over 30 kW created a situation where DG projects did not receive funding. This limitation on funding for viable projects would be mitigated by reducing the incentive payment levels.

2. Eliminating the maximum percentage payment caps would reduce the administrative costs of the program and simplify it.

3. Several incentive programs are available for distributed generation projects and may provide a single project with incentives that exceed costs.

4. Reducing incentives for some types of projects and eliminating the maximum percentage cap for all projects would increase the incentives available for viable projects. The existing $4.50 per watt incentive payment for renewable fuel cells does not need to be changed to address a shortage of funding for such projects.

5. No useful purpose is served by requiring projects on SGIP waiting lists to reapply for funds in subsequent funding cycles.

6. Increasing the maximum eligible capacity size to 5 megawatts, but retaining incentive payments up to 1 megawatt, would promote more cost-effective projects to the benefit of ratepayers and utility operations while maintaining enough funds to provide incentives to a number of viable projects.

7. Developing a data release format that resembles that used by the CEC for its Emerging Renewable Incentives Program and requiring developers to make project information available at their websites would improve the usefulness of information related to DG.

8. An incentive structure that predictably declines over time would promote a smooth transition to a market unsupported by SGIP rebates.

9. Developing a cost-benefit methodology for DG projects will assist in the evaluation of the program and related projects. SDG&E is expected to exercise prudent oversight of its contract with SDREO for administrative services to ensure that SDREO is performing those services effectively and consistent with program guidelines. At the same time, SDG&E's oversight should not entail unreasonable duplication of effort or unreasonably delay payments of incentives to qualified projects or to SDREO for administrative services rendered. SDG&E

and SDREO should negotiate additional contract terms to mitigate these issues. Energy Division should continue to mediate between SDREO and SDG&E on these issues.

10. Directing SDG&E to extend its administrative services contract with SDREO through 2007 enables the SGIP program to move forward without disruption to current program administration arrangements for the authorized funding period. At the same time, it does not preclude the Commission from reevaluating the administrative structure for SGIP if funding continues past 2007.

11. Project proponents may demonstrate air emissions compliance with AB 1685 with a certificate from CARB or by presenting relevant documentation regarding facility operational characteristics.

12. Decision 01-03-073 prohibited utility distribution companies from receiving SGIP incentives.

13. The current caps on funding for government agencies and corporate parent companies hinder the goal of increasing DG capacity and may artificially inflate project costs.

14. As discussed in this decision, the Working Group's development of a proposed exit strategy, a declining rebate schedule and a common data release format would benefit from broader public input.

Conclusions of Law

1. The SGIP incentives should be reduced for certain types of projects as set forth herein and the maximum percentage cap for such projects should be eliminated. The SGIP incentive payment of $4.50 per watt for renewable fuel cells should be retained.

2. The SGIP rules should be modified to eliminate the requirement that proponents of projects reapply for incentives in the subsequent funding cycle, according to a process developed by the Working Group.

3. The SGIP rules should account for multiple incentives that may be available for a single project and preserve existing funding resources for maximum disbursal.

4. The SGIP rules should be modified to increase the maximum eligible capacity size to 5 megawatts, but retain incentive payments only up to 1 megawatt.

5. The data release format should be modified to resemble that used by the CEC for its Emerging Renewable Incentives Program.

6. Program administrators should be required to make project information available at their websites.

7. SGIP incentives should be structured so that they predictably decline over a ten-year period. The Working Group should be directed to develop a plan to that end and the final elements of that plan should be subject to Commission approval.

8. As discussed in this decision, SDG&E should extend its contract with SDREO for program administrative services through 2007.

9. AB 1685 provides the Commission with flexibility to make changes to the SGIP, including changes in the annual program budget.

10. AB 1685 requires combustion-operated fossil-fueled DG projects to meet specified statewide emissions criteria to qualify for SGIP incentives. The program handbook should reflect these emissions and eligibility requirements and the option for project proponents to certify compliance either with documentation from the California Air Resources Board or by submitting

manufacturer emission specifications, a permit to operate, and project-specific efficiency calculations. Utilities should implement related provisions of AB 1685 as set forth herein.

11. D.01-03-073 intended that SGIP funds should not be awarded to public or investor-owned gas or electricity distribution utilities that generate or purchase electricity or natural gas for wholesale or retail sales.

12. SGIP rules should be modified to remove the restrictions limiting funding for the California state university system, other state agencies and corporate parents.

O R D E R

IT IS ORDERED that:

1. The Self Generation Incentive Program (SGIP) incentives are hereby modified as set forth herein and the maximum percentage cap for such projects is hereby eliminated. The SGIP incentive payment of $4.50 per watt for renewable fuel cells is retained.

2. SGIP incentives for all levels shall be based on installed capacity rather than a maximum percentage cap, consistent with this order.

3. The Working Group shall, within 60 days of the effective date of this order and following consultation with interested parties, develop data release formatting and publication protocols as set forth herein, and implement them within 90 days of the effective date of this order.

4. Program administrators shall post required information at their respective websites within 30 days of the effective date of this order, as set forth herein.

5. The SGIP rules are hereby modified to increase the maximum eligible capacity size to 5 megawatts, except that incentive payments are retained at the 1-megawatt level.

6. The Working Group shall, within 90 days of the effective date of this order and following consultation with interested parties, file a proposal to modify the incentive structure so that incentive amounts decline gradually over the next ten years. This exit plan shall not go into effect without subsequent Commission approval and following an opportunity for parties to comment on the Working Group filing.

7. SDG&E shall, within 30 days of the effective date of this order, submit to Energy Division, an extension to the administrative services contract with SDREO through 2007.

8. The Working Group shall, within 30 days of the effective date of this order, modify the program handbook to (1) assure a method for certification by project proponents of compliance with the air emissions standards required by AB 1685 as set forth herein; (2) eliminate the requirement that proponents of projects reapply for incentives in the subsequent funding cycle; (3) clarify the program handbook to provide that SGIP funds may not be awarded to public or investor-owned gas or electricity distribution utilities that generate or purchase electricity or natural gas for wholesale or retail sales; (4) raise from one to 4 MW the annual restrictions on funding for the California University system, other state agencies and corporations; (5) include procedural or financial mechanisms to deter inappropriate reservation requests; and (6) grant projects with multiple funding sources as set forth herein.

9. Program administrators are authorized to direct their consultant to update the September 2, 2003 comparative assessment report with data collected from

June 2003 through May 2006, for submission by September 15, 2006. The report shall clearly identify all program administrators and address the performance of each.

10. For good cause, the Assigned Commissioner or Administrative Law Judge may modify the due dates set forth in this decision.

This order is effective today.

Dated December 16, 2004, at San Francisco, California.

MICHAEL R. PEEVEY
President
CARL W. WOOD
LORETTA M. LYNCH
GEOFFREY F. BROWN
SUSAN P. KENNEDY
Commissioners

ATTACH A TO KLM R0403017